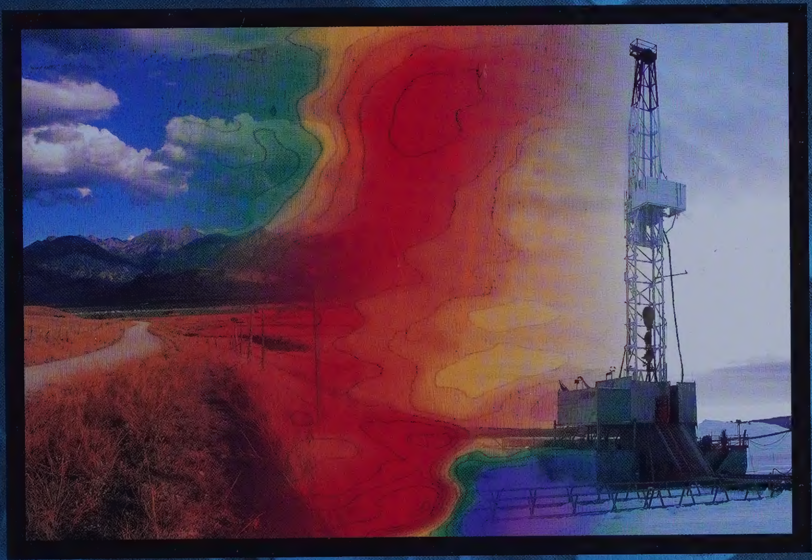
People. Prospects.
Financial Strength.



blue mountain
energy ltd

2002 ANNUAL REPORT

CORPORATE PROFILE

Blue Mountain Energy Ltd. is a Calgary, Alberta-based grassroots oil and natural gas exploration company.

Full-Cycle Exploration

The Company commenced oil and natural gas operations following a corporate restructuring and management change in June 2002. Blue Mountain is led by an experienced management team and Board of Directors. Half of the Company's managers and employees are explorationists.

Natural Gas Focus

Blue Mountain is focusing its exploration activities on three main areas along the Alberta Foothills: in the Peace River Arch, west-central Alberta and to a lesser degree southern Alberta. The Company's production at year-end 2002 was approximately 800 barrels of oil equivalent (boe) per day, about 60 percent of which was crude oil. Several successful new natural gas wells await tie-in. The majority of Blue Mountain's current and planned exploration activity is oriented to natural gas. The Company has an active exploration program planned for 2003, with $15 million budgeted.

Efficient Use of Capital

Blue Mountain is a publicly-traded corporation listed on the TSX Venture Exchange under the trading symbol "GAS". At December 31, 2002, there were 12.5 million common shares issued and outstanding. At year-end 2002, the Company had $14.7 million in working capital and no debt.

Notice of Annual General Meeting

The annual and special meeting of shareholders will be held at 2:30 p.m., June 11, 2003 in Room 201, Conference Centre - Stock Exchange Tower, 300-5th Avenue S.W., Calgary, Alberta. Shareholders are encouraged to attend. Those unable to do so should complete the form of proxy included with this annual report and return it to the Company's head office at their earliest convenience.

Contents

Cover: Blue Mountain Energy drilling rig at Spirit River, Alberta 9-16-78-7W6M.

2002 PERFORMANCE

Operating Highlights

	Q4 — Three months ended December 31, 2002	2002 — Year ended December 31, 2002
Average Production		
Crude oil (bbls per day)	402	125
Natural gas (mcf per day)	1,693	537
Natural gas liquids (bbls per day)	13	4
Total (boe per day @ 6:1)	697	219
Average Prices		
Crude oil ($ per bbl)	$ 28.21	$ 29.47
Natural gas ($ per mcf)	$ 5.72	$ 5.39
Natural gas liquids ($ per bbl)	$ 25.20	$ 25.89
Operating netbacks ($ per boe)	$ 18.41	$ 18.35
Undeveloped Land		
Gross acres	65,309	65,309
Net acres	46,289	46,289

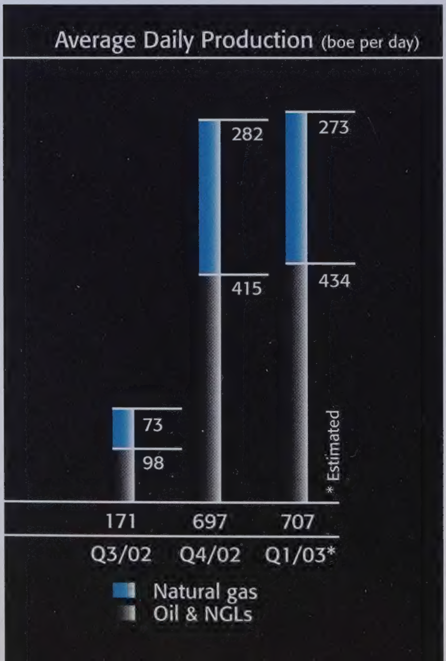
Financial Highlights

Revenues, net of royalties	$ 1,814,853	$ 2,375,082
Cash flow	999,735	1,323,465
Cash flow per share		
Basic	0.08	0.25
Diluted	0.08	0.25
Earnings	135,455	210,497
Earnings per share		
Basic	0.01	0.04
Diluted	0.01	0.04
Net capital expenditures	2,938,390	19,823,643
Cash and cash equivalents	18,153,612	18,153,612
Working capital deficiency	$ 3,427,119	$ 3,427,119
Shares outstanding	12,503,040	12,503,040
Stock options outstanding	1,266,671	1,266,671

It is with pleasure that I present you with our first annual report as Blue Mountain Energy Ltd. I welcome all of the Company's new and existing shareholders, and all of the staff of Blue Mountain, to this new and dynamic exploration Company.

The past seven months have been intense but very productive as we obtained major equity financing and established drilling momentum in a very short timeframe.

The new management team is building Blue Mountain as a pure, grassroots exploration company. We are focused on creating value through the drill bit by pursuing medium-to-high-impact opportunities in under-explored areas of Alberta or by applying new exploration or exploitation concepts to acquisitions that include existing production. We are focusing primarily on the area along the Alberta Foothills, a region that holds medium-depth to deep, multi-zone reservoirs offering potential for high productivity and large reserves. We are aiming for reserves of 1-5 bcf or 250 mbbls per discovery well. We also favour areas that are accessible year-round to reduce the cycle time from spud to production. The overall goal is an economically sound onstream cost for all new reserves.



Blue Mountain's targeted exploration region in our view represents a higher risk, higher return and higher quality of reserves model than the typical historical junior development plan, which focused on lower-risk, lower-deliverability shallow gas on the Prairies. However, we believe that a small company, if led by an experienced management team applying sound technical standards and prudent financial practices, can operate successfully in this higher-risk environment and create significant new value for shareholders.

2002 Milestones

May – Blue Mountain Energy was essentially an empty shell. A new senior team was assembled, comprised of Brent Foster, Vice President, Engineering; Nick Wemyss, Vice President, Exploration; Dale Joynt, Chief Financial Officer; and myself as President and C.E.O.; with additional help from Verne Johnson, a pending member of the Board of Directors. The new team began prospecting immediately.

June – First Energy Capital Corp. raised $20 million in new equity. The management team and directors, including newly elected board member Carl-Martin Nagel, used personal funds to purchase a further $3 million in common equity. Net proceeds of the $23 million financing were $21.6 million.

July – The new team became aware of an excellent opportunity to acquire a public company, Bolt Energy Ltd., with an attractive inventory of natural gas exploration prospects, suitable exploration staff and an existing production base. Blue Mountain offered to purchase Bolt using Blue Mountain shares.

September – Following shareholders' acceptance of Blue Mountain's offer, the Company took control of Bolt Energy Ltd. Bolt founder Ray Chiarastella joined Blue Mountain as Vice President, Land. Three former Bolt geologists, Earl Tobin, Sherman Hirowatari, and Tyson Brown, also joined Blue Mountain. Bolt director Jim Banister became an advisor to the Blue Mountain Board until his planned nomination to the Board at Blue Mountain's next annual general meeting.

October – Through the buy-out of the assets of a private company, Blue Mountain acquired 17,600 net acres of prospective drilling acreage at 100 percent working interest, concentrated in Blue Mountain's chosen areas of interest.

November – To reduce the risk level facing Blue Mountain's shareholders, the Company negotiated joint venture participation in its wildcat drilling program. Blue Mountain's new partner agreed to fund 70 percent of drilling costs to earn a 40 percent working interest after casing or abandonment.

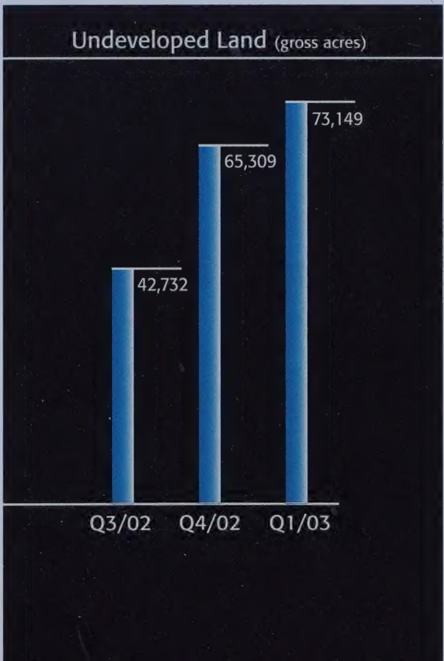
Before year-end 2002 – Blue Mountain drilled 13 gross wells, operating 11 of these, of which the joint venture partner participated in the final six wells. The drilling program resulted in doubling oil production at the Forest Bank property and notable discoveries at Spirit River and Ferrybank. The Spirit River well (60 percent working interest) drill-stem tested natural gas in two separate zones at 10.9 mmcf per day and 1.1 mmcf per day. The Ferrybank well (60 percent working interest) production tested at 1.5 mmcf per day.

2002 Results

Blue Mountain's reason for existence, of course, is to deliver results. Upon completing our financing and restructuring, the Company's asset value was approximately $2.55 per share. In the following six months, we have been able to increase that value to $3.42 per share while generating significant exploration momentum.

By year-end Blue Mountain had drilled 13 gross wells, 11 of them Company-operated. Our capital expenditures for the year, including the two significant acquisitions, totalled $19.8 million. We had grown our land base to 53,000 net acres at an average working interest of 76 percent. Production had risen to approximately 800 boe per day and was continuing to grow in January.

Having incurred negligible negative cash flow in the second quarter, we were modestly cash flow-positive by the third quarter and generated $1.0 million ($0.08 per share basic and diluted) cash flow in the fourth quarter. Net income was $0.2 million ($0.04 per share basic and diluted) for the period ended December 31, 2002. We closed the year with zero long-term debt, $14.7 million in working capital and production of 817 boe per day.



Growth Philosophy

It is our intention to grow through the drill bit. We will make acquisitions of producing properties or corporations if they add value to our shareholders and enhance our exploration prospects. But primarily we are interested in acquiring undeveloped lands with strong exploration prospects. Our chosen corporate risk profile is a majority of medium-risk exploratory wells complemented by a small number of carefully selected high-impact, high-risk wildcats. We are aiming for major value creation.

Blue Mountain seeks operatorship of all its prospects. Our working interest will depend on our risk evaluation and the capital exposed. It will probably average 60-80 percent to cap the risk exposure while preserving strong upside potential. We attempt to reduce our shareholders' risk by laying off a portion of the drilling costs on a promoted basis where our dollar exposure would otherwise be too high. This was evident in our 2002 program, where an investment fund paid for 70 percent of the last six wells to earn a 40 percent interest after rig release. This enabled Blue Mountain to retain a working interest of 60 percent while funding only 30 percent of the drilling costs.

The Year Ahead

Blue Mountain is planning an active exploration and development program for 2003. I'm pleased at the strengths we have working in our favour, including:

- $14.7 million of working capital and an operating line of credit totalling $6.7 million, none of which is drawn;
- 10-15 new exploration prospects to drill;
- Two development locations to drill at Ferrybank;
- New natural gas production to tie-in at Ferrybank, which should be generating cash flow by the second quarter, increasing in the fourth quarter with successful development drilling;
- Record commodity prices; and
- A technically very able and strongly motivated team.

The year ahead, in other words, holds a great deal of promise. During the first quarter we focused mostly on completions, tie-ins and evaluation of our newly drilled wells. An active drilling program will follow in the second and third quarters. Capital spending for the year is estimated at $15 million, but our budget will be adjusted according to drilling results and emerging opportunities. We are basing our 2003 plans on price assumptions of US$26.00 per barrel of W.T.I. crude oil and Cdn$5.15 per mcf of natural gas at AECO. At these prices, and assuming a reasonable level of development success, Blue Mountain's quarterly cash flow could reach $2 million by the fourth quarter.

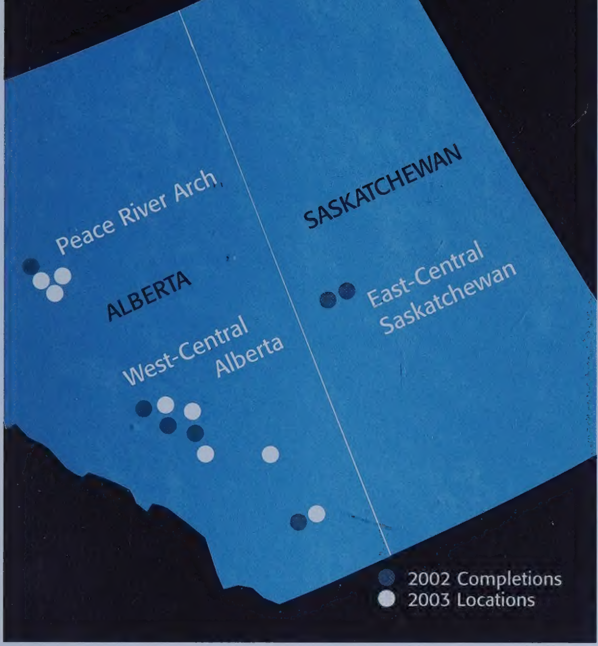
However, it is important to remember that true oil and natural gas exploration is a high-risk endeavour, no matter how well-managed a company may be. As I tell investors and analysts at many of my presentations: "We have the people, the prospects, and the money, we need a continuation of good luck." All explorationists face a degree of irreducible risk. It's just the nature of the business.

On behalf of the Board of Directors,

Randy Pawliw

Randy Pawliw
President and Chief Executive Officer

March 10, 2003



EXPLORATION REVIEW

Strategic Overview

Blue Mountain is a recently reorganized (Q2 2002) Company with a primary strategic focus on creating value through exploration drilling. Blue Mountain has decided to focus on the exploration areas of west-central Alberta and the Peace River Arch region of northwestern Alberta. These areas are natural gas-prone with multi-zone potential from very shallow (300 metres) through deep (3,000 metres). Further attractive characteristics include largely year-round access, extensive infrastructure including natural gas pipelines, and remaining available undeveloped lands through Crown sales or negotiated participation.

Blue Mountain's strategy is consistent with the current maturity of the Western Canada Sedimentary Basin. Natural gas reserves generally increase proportionately with depth, while drilling density decreases and mineral rights become more easily available. It is widely agreed that remaining meaningful new pool discoveries in Alberta will be deeper, riskier and more expensive to attain, but Blue Mountain firmly believes they will occur.

Blue Mountain's technical staff have decades of successful exploration to their credit and development expertise with the formations in this part of the Western Canada Sedimentary Basin. The Company plans to focus most of its drilling at depths of less than 1,800 metres, preferably with several stacked targets and including offset development potential. Blue Mountain will also seek to include at least one "home-run hit" as deep as 3,000 metres in its yearly portfolio that is capable of significant impact to shareholders.

Blue Mountain's strong technical staff will generate most of the Company's drilling program internally, but the Company will continue to evaluate asset sales and joint ventures where there is a fit to its geographical and product focus. Riskier prospects will be managed through promoted partnerships to reduce the Company's cash exposure. In late 2002 the Company entered into such an agreement to reduce risk at one of its major prospects.

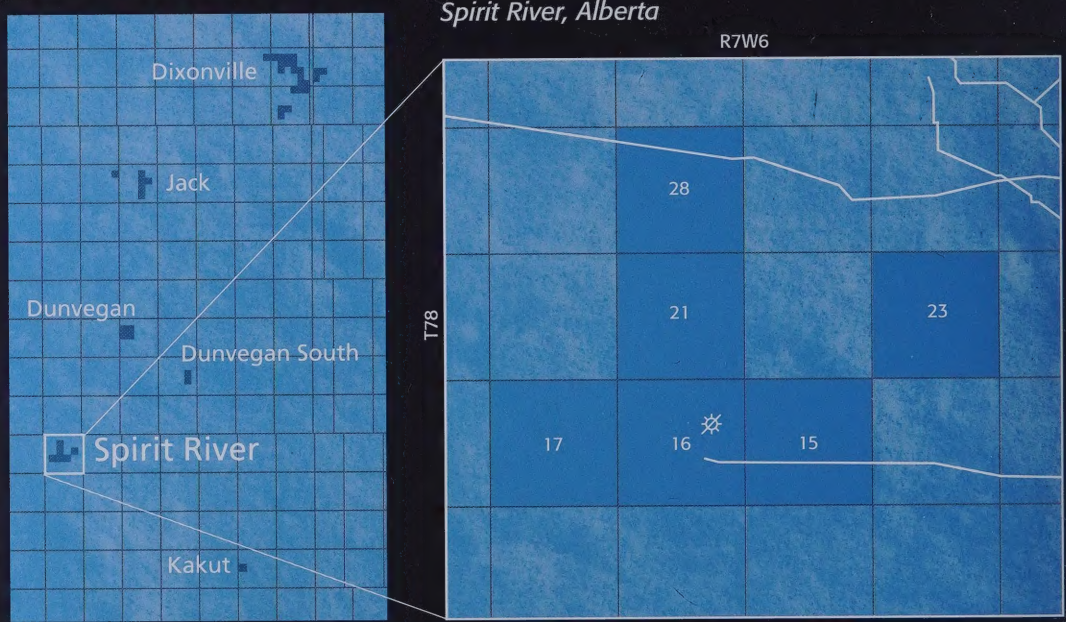
In September 2002 Blue Mountain completed a significant acquisition of a publicly held company, Bolt Energy Ltd., that included production and undeveloped lands, many of them lying in Blue Mountain's focus areas. Subsequent evaluation yielded recognition of exploration upside and development/ optimization potential of the existing production. Immediate commencement of a mixed program of exploration, development and optimization resulted in production being increased to 800 boe net at year-end 2002, as well as two new pool natural gas discoveries. Since the acquisition several new prospects have been developed and adjoining prospective lands acquired which are forming the core of Blue Mountain's 2003 drilling program.

Review of Properties

West-Central Alberta and the Peace River Arch regions offer largely year-round access, extensive infrastructure and access to remaining available undeveloped lands through Crown sales or negotiated participation.

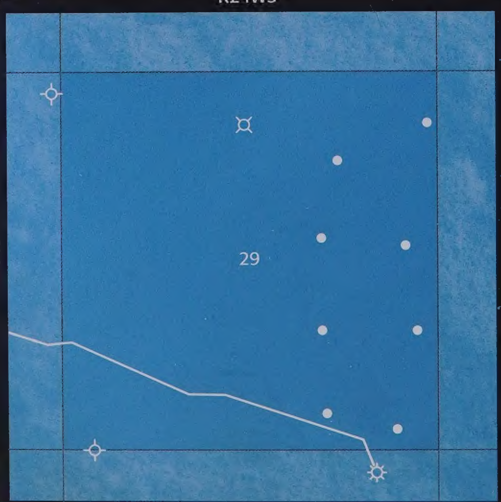
Peace River Arch

Spirit River, Alberta



The Spirit River property is expected to be producing at least 1 mmcf per day net to Blue Mountain by autumn 2003.

East-Central Saskatchewan



Blue Mountain Energy land
Natural gas well
Oil well
Pipeline
Dry & abandoned
Water disposal
Suspended gas

Forest Bank, Saskatchewan

Production at Forest Bank has increased from 220 bbls per day in September 2002 to 400 bbls per day in February 2003.

Spirit River, Alberta

Blue Mountain has an average 60 percent working interest in and operates eight sections (3,072 net acres) of undeveloped land at Spirit River.

This area of the Peace River Arch is typical of the region's natural gas-prone, multi-zone opportunities that can yield production from 300 metres to 3,000 metres depth. One section of this property, focusing on a Triassic gas opportunity, was acquired with the Bolt acquisition, while the remaining seven sections were subsequently acquired through Crown land sales, after drilling had confirmed significant natural gas.

In December 2002 Blue Mountain drilled a deep exploratory wildcat to 2,800 metres at 9-16-78-7W6. Recently acquired proprietary 2D seismic had identified a multi-zone natural gas opportunity. One sand in this well drill-stem tested sour natural gas at a rate of 10.9 mmcf per day. The other sand drill-stem tested sweet natural gas at 1.1 mmcf per day. The Wabamun is very deep at 2,800 metres and was drilled to evaluate in the new year. Drill-stem test results were negative in the Wabamun and the zone will be tested through casing.

Blue Mountain's discovery well is close to a sweet natural gas pipeline, facilitating tie-in of the sweet natural gas after production testing of all potential zones. The sour zone will be tied-in after production of the sweet reserves to a sour natural gas pipeline and processing facility. The Spirit River property is expected to be producing at least 1 mmcf per day net to Blue Mountain by autumn 2003.

The seven additional undeveloped sections of 60 percent interest lands show potential from mapping regional 2D seismic lines. Blue Mountain is currently shooting a detailed proprietary 2D seismic program to delineate drilling locations for at least one summer exploration well. The Company believes this property holds strong upside potential. Spirit River is the centre of an active shallow and deep natural gas-focused exploration program. Blue Mountain expects to drill up to four rank exploration wildcats in 2003.

Forest Bank, Saskatchewan

Blue Mountain operates a 100 percent working interest section (640 acres) of developed land southeast of Lloydminster, Saskatchewan.

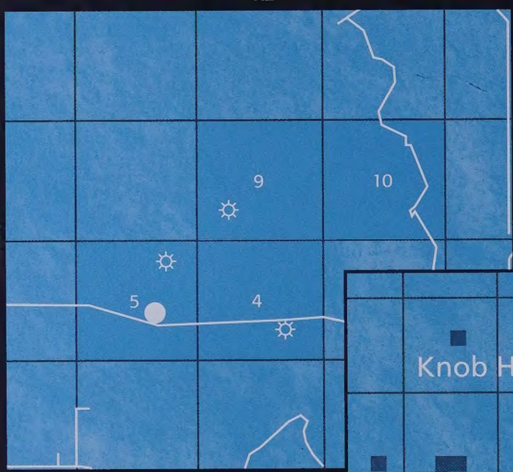
Upon acquisition as part of the Bolt transaction, this property was producing 220 bbls per day from four wells in the lower Mannville sands at 750 metres. Each well was equipped with a single-well battery, and co-produced formation water was trucked for disposal at a third-party site.

In Q3 2002 Blue Mountain drilled three wells to fully develop this pool. Two were completed as multiple-zone Mannville heavy oil wells and the third was completed as a service well for water disposal. Disposal of water associated with oil production can be a significant cost. Using the 14-29 well for water disposal has reduced Blue Mountain's field operating costs at Forest Bank from \$12.50 per bbl to \$9.60 per bbl of production.

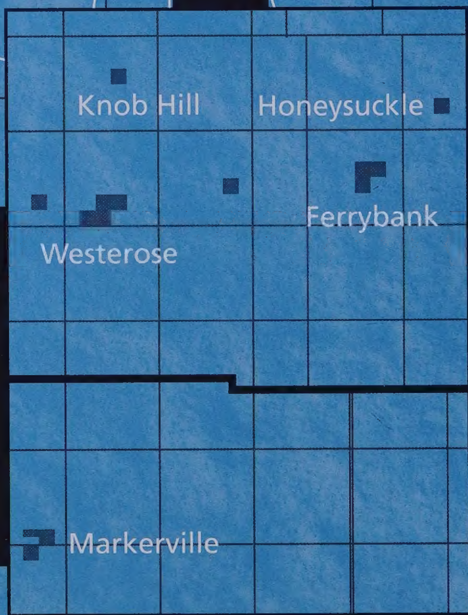
The 9-29 well has averaged 26 bbls per day since completion, while the 15-29 well has averaged 95 bbls per day since completion. Combined with an aggressive recompletion and optimization program begun last fall, production at Forest Bank has increased from 220 bbls per day in September 2002 to 400 bbls per day in February 2003. Blue Mountain will continue to optimize production from this pool. The Company is not planning further investment in this area as it does not fit Blue Mountain's western Alberta natural gas exploration focus.

West-Central Alberta

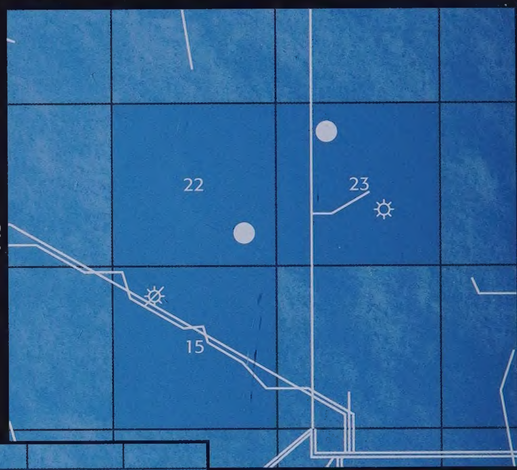
Westerose



Blue Mountain drilled and completed a test well at 16-5-45-2W5 and confirmed gas production potential in the Edmonton and Paskapoo formations.



Ferrybank



This area has multiple natural gas zones from 500-1,800 metres depth that generate long-life production with reserves of 1-5 bcf per successful well.

Markerville

This multi-zone area has production from shallow gas sands at 500 metres down to Mississippian limestone at 2,000 metres.

Blue Mountain Energy land
2003 location
Natural gas well
Pipeline
Suspended gas
Oil and natural gas well

Ferrybank, Alberta

Blue Mountain has an average 60 percent working interest and operates three sections (1,920 acres) of land at Ferrybank.

This area has multiple natural gas zones from 500 metres to 1,800 metres depth that generate long-life production with reserves of 1-5 bcf per successful well. Of Blue Mountain's current three sections of land, one undeveloped section was held by Bolt, another undeveloped section was acquired through a farm-in commitment well at 14-15-45-27W4, and the third section, which included a suspended natural gas well, was purchased in early 2003. There was no production from these lands at the time of their acquisition.

Blue Mountain's farm-in well at 14-15 was drilled in December 2002 and was completed for Glauconitic Formation natural gas production at 1.5 mmcf per day, flowing at 875 psi. This well will be followed up by two further locations. Blue Mountain purchased a 100 percent working interest shut-in well at 7-23-45-27W4 and recompleted the well for production of 470 mcf per day at 375 psi.

Blue Mountain expects to tie-in these wells by summer 2003 at a net rate of 3 mmcf per day. The Company is actively prospecting for new exploration opportunities and evaluating nearby acquisitions. This area is Blue Mountain's most active west-central Alberta natural gas exploration area. Blue Mountain plans to grow high-quality assets in this region over the life of the Company.

Markerville, Alberta

Blue Mountain operates and has a 60 percent working interest in 2.5 sections (1,600 acres) of land at Markerville, assembled through the Bolt acquisition and subsequent purchases of undeveloped land.

This multi-zone area has production from shallow gas sands at 500 metres down to Mississippian limestone at 2,000 metres. Lands in this area constantly turn over, with a mixture of Crown and freehold available for acquisition. These highly prospective characteristics make this property, which has no current production, an active prospecting area for Blue Mountain. An exploration well drilled in December 2002 at 13-2-36-3W5 was cased for dual-zone hydrocarbon production. The well is currently being completed. A successful completion would generate at least one follow-up well.

Westerose, Alberta

Blue Mountain has a 50 percent working interest in four sections (2,560 acres) of land at Westerose acquired with the Bolt acquisition.

Blue Mountain drilled and completed a well at 16-5-45-2W5 to test shallow gas sands in the Edmonton and Paskapoo formations at 400-750 metres depth. Recent exploration discoveries in this area confirmed the natural gas production potential in these new zones. The reservoir encountered was thinner than expected and the well is currently being reviewed for tie-in.

At acquisition the property was producing 500 mcf per day net, a rate that has declined to 200 mcf per day by Q1 2003. Two recently drilled wells are awaiting tie-in and may contribute an additional 100 mcf per day. Blue Mountain is evaluating the options of increasing its interest in the wells or putting its interest up for sale. Results to date have not met the Company's expectations. Blue Mountain believes there is potential to realize value by assuming operatorship and optimizing production.

The following discussion and analysis as provided by the management of Blue Mountain Energy Ltd. should be read in conjunction with the financial statements presented in this annual report.

Boe Presentation

Natural gas is converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel unless otherwise stated. This conversion conforms with the Canadian Securities Regulators' proposed National Instrument 51 – 101 – Standards of Disclosure for Oil and Gas Activities.

Production

Blue Mountain Energy Ltd. acquired Bolt Energy Ltd. effective September 5, 2002 and prior to that date had no oil or natural gas production. At the time of acquisition, Bolt was producing approximately 665 boe per day. Total reported Blue Mountain sales volumes of 219 boe per day for 2002 include volumes only from the acquisition date, which are distributed over the entire year and are therefore not indicative of actual production capacity. In the fourth quarter of 2002, which is a more accurate representation, sales volumes averaged 697 boe per day.

Sales of crude oil averaged 402 bbls per day in the fourth quarter (125 bbls per day annualized).

Natural gas sales averaged 1,693 mcf per day in the fourth quarter (537 mcf per day annualized).

Average natural gas liquids sales were 13 bbls per day in the fourth quarter (4 bbls per day annualized).

	Crude Oil (bbls per day)				Natural Gas Liquids (bbls per day)				Natural Gas (mcf per day)			
	Total 2002	%	Q4 2002	%	Total 2002	%	Q4 2002	%	Total 2002	%	Q4 2002	%
Cantuar	29	23	89	22	–	–	–	–	–	–	–	–
Dixonville	–	–	–	–	–	–	–	–	38	7	111	6
Forest Bank	81	65	273	68	–	–	–	–	–		–	–
Grand Forks	9	7	24	6	–	–	–	–	–	–	–	–
Hays	4	3	11	3	–	–	–	–	–	–	–	–
Kaybob	–	–	–	–	1	25	3	22	105	20	295	17
Mikwan	–	–	–	–	–	–	1	8	46	9	113	7
Retlaw	–	–	–	–	–	–	1	8	13	2	122	7
Two Creek	–	–	–	–	1	25	4	31	233	43	772	46
Westerose	–	–	–	–	1	25	4	31	76	14	217	13
Other	2	2	5	1	1	25	–	–	26	5	63	4
Total	125	100	402	100	4	100	13	100	537	100	1,693	100

The corporate exit production rate was 817 boe per day, reflecting oil production increases resulting from a successful fourth-quarter drilling program at Forest Bank. Natural gas production increases, also resulting from successful fourth-quarter drilling, will materialize through the first half of 2003 as the wells are tied-in and brought on-stream.

In the first quarter of 2003, average production is estimated at approximately 745 boe per day, as mechanical problems associated with winter operations at Forest Bank reduced oil production.

Revenue

Gross sales revenues in 2002 were $2,439,542, of which $1,964,277 was generated in the fourth quarter.

For the year, crude oil revenues were $1,345,227, natural gas revenues were $1,055,485 and natural gas liquids revenues were $38,831.

In the fourth quarter, crude oil revenues were $1,042,482, natural gas revenues were $890,817 and natural gas liquids revenues were $30,978.

Interest revenue was $259,475 in 2002 and $104,306 in the fourth quarter.

Prices

Blue Mountain's wellhead price for crude oil averaged Cdn$29.47 per barrel in 2002. Average 2002 oil prices for W.T.I. and Edmonton par were US$26.36 per barrel and Cdn$39.94 per barrel, respectively. The differential reflects the components of Blue Mountain's 2002 oil production, which include Lloydminster heavy and southwest Saskatchewan medium-gravity crude.

Blue Mountain's average sales price for natural gas, net of transportation, was $5.39 per mcf in 2002. The Alberta daily spot price at AECO in 2002 averaged $4.07 per mcf. Through the four-month period in 2002 for which production is being reported, the Alberta daily spot price at AECO averaged $5.31 per mcf. A large component of Blue Mountain's natural gas production has higher than average heat content, resulting in higher than average prices.

The wellhead natural gas liquids price received by Blue Mountain in 2002 averaged $25.89 per barrel.

Expenses

Royalties

Royalties, net of the Alberta Royalty Tax Credit, were $323,935 in 2002. Royalties as a percentage of total sales were 13.3 percent. Blue Mountain's royalty rate is relatively low primarily because the majority of the oil wells at Forest Bank still qualify for royalty relief on initial production volumes of up to 50,000 barrels per well. As a result, royalty rates on oil production averaged 9 percent in 2002. Natural gas royalty rates averaged 22 percent in 2002, while the 2002 royalty rate for natural gas liquids averaged 30 percent of revenues.

Operating Expenses

Operating expenses in 2002 totalled $650,738, or $8.15 per boe of production. Operating expenses per unit of production are expected to decrease in 2003. A water disposal well drilled at Forest Bank in the fourth quarter will significantly reduce unit operating expenses at that property. New, lower cost natural gas production additions, which will be brought on-stream over the first half of 2003, will also contribute to a reduction in unit operating expenses.

General and Administrative Expenses

General and administrative expenses in 2002 were $308,541 or $3.87 per boe of production, compared to $45,715 in 2001, when the Company had no production or salaried employees. Blue Mountain capitalized $250,126 in general and administrative expenses relating to its pre-production and exploration costs in 2002.

	2002		2001	
	Total	per boe	Total	per boe
Gross general and administrative expenses	$ 558,667	$ 7.00	$ 45,715	na
Capitalized general and administrative expenses	$ (250,126)	$ (3.13)	$ –	na
Total general and administrative expenses	$ 308,541	$ 3.87	$ 45,715	na

General and administrative expenses on a per unit basis will decrease as cash reserves are converted into additional production volumes.

Interest Expense

Interest expense decreased to $29,489 in 2002 from $35,668 in 2001. The majority of interest expense in 2002 resulted from interest on notes payable, which were retired in the third quarter. The remainder of interest expense related to interest on long-term debt held by Bolt Energy Ltd., and interest payable under Part XII.6 of the Income Tax Act for flow-through shares issued in 2001 by Bolt. Blue Mountain retired the Bolt debt shortly after the acquisition, and currently has no debt obligations.

Site Restoration

The Company provides for the future estimated costs of site restoration and abandonment on a unit of production basis. At year-end, total future costs were estimated to be $700,000. The provision in 2002 was $24,611, or $0.31 per boe of production.

Depletion and Depreciation

Depletion expense for petroleum and natural gas properties was $810,797 or $10.15 per boe of production in 2002. Depreciation expense for other assets was $9,928 or $0.13 per boe.

Income and Other Taxes

Future income tax expense in 2002 was $267,632 (2001 – nil).

Capital tax expense reflects federal capital taxes payable at the rate of 0.225 percent on taxable capital in excess of $10,000,000.

At year-end, the Company had unused tax pools totalling $14.7 million, which may be used to offset future income tax liabilities.

Tax Pool Balances

	December 31, 2002
Canadian exploration expense	$ 1,970,925
Canadian development expense	3,149,556
Canadian oil and natural gas property expense	3,288,830
Undepreciated capital cost	2,628,529
Operating losses	1,124,563
Capital losses	1,254,021
Share issue costs and other	1,244,123
Total	$ 14,660,547

Cash Flow and Earnings

Cash flow from operations was $1,323,465 in 2002 compared to a cash outflow of $81,383 in 2001, when the Company had no revenue stream. Cash flow for the year was $0.25 per share basic and diluted, compared to cash outflow of $0.38 per share basic and diluted in 2001. In the fourth quarter, cash flow was $999,735, or $0.08 per share basic and diluted.

Blue Mountain's earnings increased to $210,497 in 2002 after incurring a loss of $81,383 in 2001. Earnings per share were $0.04 basic and diluted in 2002, compared to a loss of $0.38 per share basic and diluted in 2001. In the fourth quarter earnings were $135,455, or $0.01 per share basic and diluted.

Netbacks

Blue Mountain's operating netback in 2002 was $18.35 per boe and cash flow, after adding interest revenue and deducting general and administrative expenses, interest expense and capital tax expense, was $16.58 per boe. There are no comparative figures for 2001, as the Company had no production.

	2002
Crude oil ($ per bbl)	
Average sales price	29.47
Royalties	(2.58)
Operating costs	(11.76)
Netback	15.13
Natural gas ($ per mcf)	
Average sales price	5.39
Royalties	(0.99)
Operating costs	(0.56)
Netback	3.84
Natural gas liquids ($ per bbl)	
Average sales price	25.89
Royalties	(7.77)
Operating costs	(3.34)
Netback	14.78
Per boe ($ per boe at 6:1)	
Average sales price	30.56
Royalties	(4.06)
Operating costs	(8.15)
Netback	18.35
Interest income	3.25
General and administrative expense	(3.87)
Interest expense	(0.37)
Capital taxes	(0.78)
Cash flow per boe	16.58
Depletion and depreciation	(10.28)
Site restoration	(0.31)
Future taxes	(3.35)
Net earnings per boe	2.64

Capital Investment and Asset Values

Capital Expenditures

Net capital expenditures in 2002 were $19,823,623. There were no capital expenditures in 2001.

Land and seismic activity accounted for $911,497 of capital spent, while $489,546 was spent on production equipment and facilities. A total of $2,474,303 was spent drilling 13 (8.9 net) wells, resulting in two (2.0 net) oil wells, five (2.9 net) natural gas wells and one (1.0 net) water disposal well.

	2002
Land acquisition and retention	$ 662,919
Geological and geophysical	248,578
Drilling and completions	2,474,303
Production equipment and facilities	489,546
Capitalized overhead	250,126
Corporate assets	99,282
Property acquisitions	298,889
Acquisition of Bolt Energy Ltd.	15,600,000
Total capital expenditures	20,123,643
Property dispositions	(300,000)
Net capital expenditures	$ 19,823,643

Drilling Activity

	Exploration		Development		Total	
Number of Wells	Gross	Net	Gross	Net	Gross	Net
Oil	–	–	2.0	2.0	2.0	2.0
Natural gas	2.0	1.2	3.0	1.7	5.0	2.9
Service	–	–	1.0	1.0	1.0	1.0
Unsuccessful	3.0	1.6	2.0	1.4	5.0	3.0
Total	5.0	2.8	8.0	6.1	13.0	8.9

Property Acquisitions and Dispositions

Property transactions in 2002 include the acquisition of Bolt Energy Ltd., which was recorded at fair market value of $15,600,000, and the acquisition of assets in the Ferrybank area, for total acquisition costs of $15,898,889. Blue Mountain's total capital expenditures were offset by the disposition of assets in the Hoadley area for proceeds of $300,000.

Land Holdings

The Bolt acquisition provided Blue Mountain with a land base of 36,381 net acres, of which 30,995 were undeveloped. In the fourth quarter, Blue Mountain completed the acquisition of 17,935 acres of 100 percent working interest undeveloped land from a private company at a cost of $435,000, or $24.25 per acre. At year-end, the Company's undeveloped land position stood at 46,289 net acres. Blue Mountain's undeveloped land position in west-central Alberta and the Peace River Arch is a key asset in generating internal growth.

Land Holdings

At December 31, 2002 (acres)	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	60,053	42,369	13,810	6,172	73,863	48,541
Saskatchewan	5,256	3,920	890	680	6,146	4,600
	65,309	46,289	14,700	6,852	80,009	53,141

Reserves

From the effective date of the Bolt acquisition on September 5, 2002 to year-end, Blue Mountain added new reserves totalling 0.6 million boe proved (1.1 million boe proved plus probable). Property acquisitions added an additional 0.1 million boe, all proved.

The evaluation of the Bolt acquisition was based in part on reserves as determined by McDaniel & Associates Consultants Ltd. at July 1, 2002. Revisions and the reserve reconciliation that follow are based on the period from July 1, 2002 to December 31, 2002.

Based on actual well performance, 2002 revisions to previous reserve estimates resulted in a reduction of 0.1 million boe proved (0.3 million boe proved plus probable).

At December 31, 2002, net proved reserves as determined by McDaniel & Associates Consultants Ltd. were 1.6 million boe, and proved plus probable reserves were 2.4 million boe. Based on fourth-quarter 2002 production levels, this equates to a 6.3 year reserve life for proved reserves and 9.5 years for proved plus probable reserves.

Summary of Reserves

At December 31, 2002	Crude Oil (mbbls)	NGLs (mbbls)	Natural Gas (mmcf)	Mboe @ 6:1	Net Present Value ($000s) Before Tax Discounted at 10%	15%
Proved producing	582	12	1,487	842	10,709	9,979
Proved non-producing	50	55	3,933	761	10,244	9,055
Total proved	632	67	5,420	1,603	20,953	19,034
Probable	451	22	1,993	805	6,449	5,066
Proved + probable	1,083	89	7,413	2,408	27,402	24,100

Reserve Reconciliation

	Crude Oil (mbbls)			NGLs (mbbls)			Natural Gas (mmcf)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Reserves at July 1, 2002	690	350	1,040	13	5	18	2,430	909	3,339
Discoveries	54	166	220	42	18	60	3,262	1,514	4,776
Acquisitions	-	-	-	13	-	13	671	-	671
Dispositions	-	-	-	(2)	(2)	(4)	(54)	(59)	(113)
Revisions	(47)	(65)	(112)	3	1	4	(573)	(371)	(944)
Production	(65)		(65)	(2)		(2)	(316)		(316)
Reserves at Dec. 31, 2002	632	451	1,083	67	22	89	5,420	1,993	7,413

Value of Reserves

At December 31, 2002 ($000s) (before tax)	Undiscounted	Discounted 10%	15%
Proved	25,420	20,081	18,248
Probable	11,544	6,199	4,868
	36,964	26,280	23,116
Alberta Royalty Tax Credit	1,576	1,122	984
Total	38,540	27,402	24,100

Pricing Assumptions

	W.T.I. Oil US$ per bbl	AECO Gas Cdn$ per mcf
2003	26.00	5.15
2004	24.00	4.85
2005	22.90	4.65
2006	22.80	4.65
2007	23.30	4.65

Finding and On-Stream Costs

Finding and on-stream costs averaged $7.84 per proved plus probable boe, $11.51 per proved boe and $9.33 per established boe, including the effect of property acquisitions and dispositions and reserve revisions. Finding and on-stream costs for reserves added through the drill bit in 2002 averaged $3.93 per proved plus probable boe, $6.60 per proved boe and $4.93 per established boe. These costs compare very favorably to our peer group within the industry.

	2002
Acquisition expenditures, net of dispositions	$ 15,598,888
Exploration and development expenditures	4,224,755
Net capital expenditures	$ 19,823,643
Proved reserve additions (mboe)	
Reserves acquired including revisions, net of dispositions	1,083
Discoveries and extensions	640
Total proved	1,723
Probable reserve additions (mboe)	
Reserves acquired including revisions, net of dispositions	370
Discoveries and extensions	435
Total probable	805
Proved + probable reserve additions (mboe)	
Reserves acquired including revisions, net of dispositions	1,453
Discoveries and extensions	1,075
Total proved + probable	2,528
Proved finding and on-stream costs ($ per boe)	
Reserves acquired including revisions, net of dispositions	14.40
Discoveries and extensions	6.60
Total proved	11.51

	2002
Proved + probable finding and on-stream costs ($ per boe)	
Reserves acquired including revisions, net of dispositions	10.74
Discoveries and extensions	3.93
Total proved + probable	7.84
Proved + 1/2 probable finding and on-stream costs ($ per boe)	
Reserves acquired including revisions, net of dispositions	12.30
Discoveries and extensions	4.93
Total established	9.33
Recycle ratio [1]	
Proved	1.59
Established	1.97
Proved + probable	2.34

[1] *Operating netback divided by finding and on-stream costs.*

Asset Valuation

The estimated present value of Blue Mountain's proved and probable reserves is based on an evaluation conducted by McDaniel & Associates Consultants Ltd. The value of reserves represents the forecast of future net cash flow derived form the production and sale of reserves, less capital expenditures and operating costs, before the deduction of interest, income tax, site restoration costs and other corporate costs. The net present value of estimated future revenues for established reserves (proved reserves plus probable reserves risk adjusted at 50 percent), discounted at 10 percent before tax, is $24.2 million. Seismic data is assigned its estimated fair market value and undeveloped land is valued at $75 per acre.

Net Asset Value

($000s, except per share amounts and numbers of shares and options)		2002
Established reserve value, 10% discounted before tax	$	24,177
Seismic value		331
Undeveloped acreage		3,472
Working capital surplus		14,726
Net asset value basic		42,706
Exercise of in-the-money stock options		3,231
Net asset value diluted	$	45,937
Common shares outstanding		12,503,040
In-the-money options outstanding		1,180,733
Diluted		13,683,773
Net asset value per common share		
Basic	$	3.42
Diluted	$	3.36

Liquidity and Capital Resources

Working capital at December 31, 2002 was $14,726,493, compared to a working capital deficiency of $539,334 at December 31, 2001. The Company had no debt at year-end 2002. Blue Mountain had access to $6,750,000 in credit facilities, unutilized, at year-end.

In 2002, Blue Mountain issued 8,166,667 Special Warrants for gross proceeds of $23,000,000. Directors and officers of the Company subscribed to 18.4 percent of the Special Warrants offering. The Special Warrants were converted into common shares on October 24, 2002.

The Company had 12,503,040 common shares outstanding at December 31, 2002. Based on a year-end closing price of $3.15 per share, Blue Mountain's market capitalization was $39,384,576. A total of 1,070,391 shares traded during the year, representing 8.6 percent of the total shares outstanding.

Business Risks

The oil and natural gas industry is subject to numerous business risks, including the volatility of commodity prices, changes in regulatory policy and legislation, environmental and safety concerns, fluctuations in interest rates and exchange rates as well as the uncertainty regarding the addition of new reserves from exploration and development programs.

Sales prices for crude oil and natural gas, interest rates and currency exchange rates are all established by global market forces over which the Company has no control. Blue Mountain mitigates these risks through a combination of sound financial and marketing policies. The Company strives to operate its working interest activities whenever possible in order to control the timing of its expenditures and marketing of its products.

Exploration risk arising from the uncertainty of finding new reserves is mitigated by employing highly competent professionals and providing them with leading-edge technology. A careful risk/reward analysis is carried out on every project, and the Company reduces its exposure on high-risk ventures by seeking promotional opportunities and joint ventures with industry partners.

The operations of all oil and natural gas explorers and producers are subject to extensive controls and regulations imposed by various levels of government. Blue Mountain monitors and adheres to all regulations which could affect its operations and has established standards of operating practice which are designed to minimize risk to its employees, the community and the environment.

The Company also maintains comprehensive insurance coverage on its assets and operations.

Outlook

Blue Mountain will continue to focus on increasing its Alberta natural gas production in 2003. Growth will be facilitated by a $15.0 million budget, which includes $11.3 million in internal exploration and development portfolio expenditures, and a discretionary amount of $3.7 million allocated to acquisitions. Blue Mountain continuously evaluates both asset and corporate acquisition candidates, and will be opportunity driven in determining those worth pursuing. If the Company is able to identify and execute an economic and strategic transaction, the budgeted amount for acquisitions could conceivably increase as much as ten-fold. The balance of the budget is allocated to drilling approximately 15 wells, related equipment purchases and facilities construction, land acquisitions and geophysical data acquisitions. For 2003, Blue Mountain has forecast the W.T.I. reference price for oil at US$26.00 per barrel, the AECO spot price for natural gas at $5.15 per mcf, and a U.S. dollar exchange rate of $1.50.

2003 Sensitivities

($000s)	Cash flow	Earnings
Change in W.T.I. oil price by US$1.00 per barrel	128	74
Change in average field price of natural gas by Cdn$0.10 per mcf	114	66
Change in value of Canadian dollar compared to U.S. dollar by Cdn$0.01	88	51
Change of 1 percent in prime interest rate	105	61

MANAGEMENT'S REPORT

All information presented in the Annual Report is the responsibility of the Company's management. The consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada and in accordance with accounting policies detailed in the notes to the financial statements. Where necessary, the statements include estimates based on management's objective and informed judgments. Management has prepared the financial information presented elsewhere in the Annual Report and has ensured that it is consistent with the financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and that financial information is reliable and relevant.

The Audit Committee of the Board of Directors has reviewed the financial statements with management and KPMG LLP, the Company's external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Randy Pawliw
President and Chief Executive Officer

Dale Joynt
Chief Financial Officer and
Corporate Secretary

Calgary, Canada
April 9, 2003

AUDITORS' REPORT

We have audited the consolidated balance sheets of Blue Mountain Energy Ltd. as at December 31, 2002 and 2001 and the consolidated statements of earnings (loss) and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP
Chartered Accountants

Calgary, Canada
April 9, 2003

Consolidated Balance Sheets

As at December 31,	**2002**	2001
Assets		
Current assets		
Cash and cash equivalents	$ 18,153,612	$ 24,316
Accounts receivable	1,508,629	207
	19,662,241	24,523
Property, plant and equipment (note 4)	19,284,779	300,000
Goodwill	3,740,547	–
	$ 42,687,567	$ 324,523
Liabilities & shareholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 4,935,748	$ 80,100
Notes payable (note 2)	–	483,757
	4,935,748	563,857
Provision for future site restoration	205,958	–
Future income taxes (note 7)	2,349,870	–
	7,491,576	563,857
Shareholders' equity		
Share capital (note 5)	39,253,031	4,028,203
Deficit	(4,057,040)	(4,267,537)
	35,195,991	(239,334)
Commitment (note 9)		
	$ 42,687,567	$ 324,523

See accompanying notes to the consolidated financial statements.

Approved by the Board,

Verne Johnson
Director

Randy Pawliw
Director

Consolidated Statements of Earnings (Loss) and Deficit

For the year ended December 31,	**2002**	2001
Revenues		
Oil and gas sales	$ 2,439,542	$ –
Royalties, net of ARTC	(323,935)	–
	2,115,607	–
Interest income	259,475	–
	2,375,082	–
Expenses		
Operating	650,738	–
General and administrative	308,541	45,715
Interest expense	29,489	35,668
Provision for site restoration	24,611	–
Depletion and depreciation	820,725	–
	1,834,104	81,383
Earnings (loss) before income and other taxes	540,978	(81,383)
Income and other taxes (note 7)		
Capital	62,849	–
Future	267,632	–
	330,481	–
Net earnings (loss)	210,497	(81,383)
Deficit, beginning of year	(4,267,537)	(4,186,154)
Deficit, end of year	$ (4,057,040)	$ (4,267,537)
Weighted average number of shares outstanding:		
Basic	5,266,017	214,242
Diluted	5,325,026	225,522
Basic earnings (loss) per share	$ 0.04	$ (0.38)
Diluted earnings (loss) per share	$ 0.04	$ (0.38)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flow

For the year ended December 31,	2002	2001
Cash provided by operating activities		
Net earnings (loss)	$ 210,497	$ (81,383)
Add (deduct) non-cash items:		
Provision for site restoration	24,611	–
Depletion and depreciation	820,725	–
Future income tax expense	267,632	–
Cash flow from (used in) operations	1,323,465	(81,383)
Change in non-cash working capital items	902,449	41,134
	2,225,914	(40,249)
Cash provided by financing activities		
Issuance of shares, net of issue costs	21,913,729	–
Cash available for investing activities	24,139,643	(40,249)
Cash used in investing activities		
Business combination (note 3)	(589,400)	–
Additions to property, plant and equipment	(4,206,615)	–
Acquisitions of oil and gas properties	(298,889)	–
Dispositions of oil and gas properties	300,000	–
Change in non-cash working capital items	(1,215,443)	–
	(6,010,347)	–
Change in cash and cash equivalents	18,129,296	(40,249)
Cash and cash equivalents, beginning of year	24,316	64,565
Cash and cash equivalents, end of year	$ 18,153,612	$ 24,316
Cash flow from (used in) operations, per share (note 5):		
Basic	$ 0.25	$ (0.38)
Diluted	$ 0.25	$ (0.38)
Supplemental cash flow information:		
Cash interest paid	$ 12,905	$ –

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2002 and 2001

1. Significant Accounting Policies:

The consolidated financial statements of Blue Mountain Energy Ltd. (the "Company") have been prepared by management in accordance with generally accepted accounting principles in Canada. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared using careful judgment with reasonable limits of materiality and within the framework of the significant policies summarized below:

(a) Basis of Presentation:

The consolidated statements include the accounts of the Company and its subsidiaries. The Company has a 100 percent interest in Bolt Energy Ltd. ("Bolt"), an active oil and natural gas exploration and production company operating in the Western Canada Sedimentary Basin.

(b) Petroleum and Natural Gas Properties:

The Company follows the full cost method of accounting for petroleum and natural gas properties whereby all costs related to the exploration and development of petroleum and natural gas properties, including applicable overhead expenses, are capitalized. The proceeds of disposition of petroleum and natural gas properties are deducted from capitalized costs, with no gain or loss calculated unless such disposal would alter the annual depletion rate by 20 percent or more.

(c) Depletion and Depreciation:

Costs related to petroleum and natural gas properties are depleted on the unit-of-production basis, based on the Company's share of total proved petroleum and natural gas reserves as determined by independent engineers. Costs eligible for depletion include total capitalized costs, less the cost of unproved properties, plus estimated future development costs of proved undeveloped reserves. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion until it is determined whether proved reserves are attributable to the properties or impairment occurs. Natural gas volumes are converted to equivalent barrels of crude oil on the basis of relative energy content, where six thousand cubic feet of natural gas equates to one barrel of oil.

The costs of corporate and other capital assets are depreciated at rates approximating their useful life on a declining balance basis of 20 percent per year.

(d) Ceiling Test:

The Company applies a ceiling test to capitalized costs, less accumulated depletion and depreciation, related to petroleum and natural gas properties to ensure that these costs do not exceed the estimated value of future net revenue from the production of proved reserves plus the lower of cost or estimated fair market value

1. Significant Accounting Policies (continued):

of unproved properties, less estimated future administrative costs, future site restoration costs, financing costs and income taxes. Future net revenues are based on prices in effect at period end. Any additional provisions required are charged to earnings as depletion and depreciation expense.

(e) *Mineral Properties:*

Costs relating to the acquisition, exploration and development of mineral properties are capitalized on an area-of-interest basis. These expenditures will be charged against earnings, through unit-of-production depletion, when properties are developed to the stage of commercial production. Where the Company's exploration commitments for an area of interest are performed under option agreements with a third party, the proceeds of any option payments are applied to the area of interest to the extent of costs incurred. The excess, if any, is credited to operations. If an area of interest is abandoned or management determines there is an other-than-temporary decline in value, the related costs are charged to earnings.

The Company's mineral property activities have primarily focused on exploration directed toward the discovery of mineral resources. When it is determined that a future reclamation cost related to mineral properties is likely, and the amount can be reasonably estimated, the costs thereof will be accrued.

(f) *Reclamation Costs:*

Estimated future site restoration and abandonment costs related to petroleum and natural gas properties are charged against earnings using the unit-of-production method. Costs are estimated by the Company based on current regulations, costs, technology, and industry standards. At December 31, 2002, the Company estimates this cost to be $700,000.

(g) *Measurement Uncertainty:*

The amounts recorded for depletion and depreciation of oil and natural gas properties, the provision for site restoration and abandonment costs and the ceiling test are based on estimates. These estimates include proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements of future periods could be significant.

(h) *Goodwill:*

Goodwill represents the excess of the cost of the acquisition (see note 3) over the net of the amounts assigned to assets acquired and liabilities assumed. In August 2001, the Accounting Standards Board of the Canadian Institute of Chartered Accountants ("CICA") issued Handbook Section 3062, Goodwill and Other Intangible Assets. Under Section 3062, goodwill and intangible assets with indefinite lives are not amortized.

The Company monitors its goodwill balance to determine whether any impairment has occurred. If this review indicates that goodwill will not be recovered based on its fair value, the Company recognizes a write-down of the unamortized portion of goodwill in excess of the fair value.

(i) Foreign Currency Translation:

Foreign currency transactions and balances of the Company are translated using the temporal method. Under this method, monetary assets and liabilities are translated at period-end rates and non-monetary assets and liabilities are translated at rates prevailing at the transaction dates. Revenues and expenses are translated at the average rate for the period. Gains and losses are recognized in earnings.

(j) Income Taxes:

The Company uses the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted, or substantively enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(k) Joint Ventures:

Certain of the Company's petroleum and natural gas exploration and production activities are conducted jointly with others. These financial statements include only the Company's proportionate interest in such activities.

(l) Stock-based Compensation:

Effective January 1, 2002, the Company adopted the recommendations of the Canadian Institute of Chartered Accountants Handbook Section 3870, Stock-based Compensation and Other Stock-based Payments. The new recommendations are applied prospectively to all stock-based payments to non-employees and to employee awards that are direct awards of stock, call for settlement in cash or other assets, or are stock appreciation rights that call for settlement by the issuance of equity instruments, granted on or after January 1, 2002.

The recommendations encourage, but do not require, the use of the fair value method of accounting for all stock-based employee compensation plans. The Company has chosen not to use the fair value method to account for stock-based employee compensation plans and therefore, the Corporation records no compensation expense when options are issued to employees. Any consideration paid by employees on the exercise of options is credited to share capital. The Corporation discloses the pro-forma effect of accounting for these awards under the fair value method (see note 6).

(m) Per Share Amounts:

Diluted per share amounts are calculated using the treasury stock method. Diluted calculations reflect the weighted average incremental common shares that would be issued upon exercise of dilutive options and warrants assuming the proceeds would be used to repurchase shares at average market prices for the period. Anti-dilutive options and warrants are not included in the calculation.

(n) Cash and Cash Equivalents:

Cash and cash equivalents include bank deposits and guaranteed investment certificates with original maturities of 90 days or less.

1. Significant Accounting Policies (continued):

(o) Financial Instruments:

The Company may utilize derivative financial instrument contracts to reduce its exposure to commodity price fluctuations. These contracts are designated, and are effective as, hedges and are not utilized for speculative purposes. Payments and receipts on these contracts are recognized in sales revenue at the time of sale of the related production.

For cash flow hedges, effectiveness is achieved if the changes in the cash flows of the derivative substantially offset the changes in the cash flows of the hedged position and the timing of the cash flows is similar. Effectiveness for fair value hedges is achieved if the fair value of the derivative substantially offsets changes in the fair value attributable to the hedged item. In the event that a derivative does not meet the designation or effectiveness criteria, the gain or loss on the derivative is recognized in earnings. If a derivative that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the gain or loss on the hedged transaction is recognized.

2. Financing and Reorganization:

On May 13, 2002, the Company announced that it entered into an agreement for a best efforts private placement financing to issue Special Warrants at a post share consolidation price of $3.00 per Special Warrant for gross proceeds of $20,000,000. Each Special Warrant entitled the holder to acquire one Common Share of the Company at no additional cost. In addition, management and certain directors of the Company subscribed for $3,000,000 of Management Special Warrants at an average price of $2.00 per Special Warrant. The financing was conducted in conjunction with the reorganization of the Company. The Company, as part of the reorganization, consolidated the Common Shares of the Company on a 12.5:1 basis and reduced the balance of notes payable, excluding interest, by $245,000 from approximately $425,000 to $180,000. The Company entered into agreements with certain debt holders who conditionally agreed to reduce the aggregate amount of debt held by them by approximately $310,000, resulting in total notes payable, including interest, of approximately $190,000. Management undertook the reorganization to restructure the Company into an oil and natural gas exploration and development company, with the objective of acquiring, exploring, and exploiting oil and natural gas assets within the Western Canada Sedimentary Basin. The funds raised pursuant to the financing were held in trust until shareholders approved the reorganization at the Annual General Meeting and necessary regulatory approvals were received. The funds were subsequently released to the Company on July 18, 2002.

On October 22, 2002, final receipts were issued for Blue Mountain Energy Ltd.'s Prospectus, which qualified an aggregate of 8,166,667 Common Shares to be issued upon the exercise of an equivalent number of previously issued Special Warrants. On October 24, 2002, all of the Special Warrants were deemed to have been converted to Common Shares.

3. Business Combination:

Effective September 5, 2002, the Company acquired all of the issued and outstanding shares of Bolt for $13,299,674. Share consideration consisted of 4,122,130 Common Shares valued at $3.00 and the fair value of Bolt options rolled over, estimated at $343,884 using the Black-Scholes option pricing model, for total share and option consideration of $12,710,274. Cash transaction costs totalled $589,400. The purchase resulted in an excess purchase price over the fair value of assets acquired of approximately $3.7 million which has been reflected as goodwill. The acquisition of Bolt provided the Company with an immediate undeveloped land and operating position in core properties in Alberta and Saskatchewan which the Company is developing through further exploration and development of these properties. The transaction has been accounted for using the purchase method, with the results of operations of Bolt being included in the statements of earnings and deficit from September 5, 2002.

The purchase price was allocated as follows:

Current assets	$ 1,161,235
Property, plant and equipment	15,600,000
Goodwill	3,740,547
Current liabilities	(4,337,698)
Future site restoration	(181,347)
Future income taxes	(2,683,063)
	$ 13,299,674

Bolt was amalgamated with the Company on January 1, 2003.

4. Property, Plant and Equipment:

December 31, 2002	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 19,724,360	$ 828,936	$ 18,895,424
Mineral properties	600,213	300,213	300,000
Office equipment	99,283	9,928	89,355
	$ 20,423,856	$ 1,139,077	$ 19,284,779

December 31, 2001	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ –	$ –	$ –
Mineral properties	600,213	300,213	300,000
Office equipment	–	–	–
	$ 600,213	$ 300,213	$ 300,000

Costs of undeveloped land amounting to $3.0 million at December 31, 2002 (2001 – nil) have been excluded from the depletion calculation.

General and administrative expenses of $250,126 were capitalized in 2002 (2001 – nil).

5. Capital Stock:

(a) Authorized:

Unlimited number of voting Common Shares.

Unlimited number of voting First Preferred Shares, issuable in series, none of which have been issued.

Unlimited number of Second Preferred Shares, issuable in series, voting rights to be determined, none of which have been issued.

(b) Issued:

	Number	Amount
Common Shares		
Balance, December 31, 2000	10,712,125	$ 4,028,203
Share consolidation at 4:1	(8,034,094)	–
Balance, December 31, 2001	2,678,031	4,028,203
Share consolidation at 12.5:1 (note 2)	(2,463,788)	–
Issued to effect business combination (note 3)	4,122,130	12,710,274
Issued for cash, less issue costs of $1,401,658 net of future tax effect of $600,825 (note 2)	8,166,667	22,514,554
Balance, December 31, 2002	12,503,040	$ 39,253,031

During 2001, the Company consolidated its Common Shares on a 4:1 basis, and during 2002, as a condition of the financing and reorganization (note 2), the Company further consolidated its Common Shares on a 12.5:1 basis. All per share amounts have been retroactively adjusted to reflect the consolidations.

(c) Performance Warrants:

As part of the financing and reorganization of the Company, 408,333 Performance Warrants were issued to current management and to certain directors, officers, employees and consultants of the Company (note 2). Each Performance Warrant is exercisable into one Common Share at a price of $3.00 per Common Share upon achievement of either performance target as defined below:

If at least 1,250,000 Common Shares have traded at or above $4.70 per Common Share within a two year period from July 18, 2002 or at least 2,000,000 Common Shares have traded at or above $9.15 per Common Share within a five-year period from July 18, 2002; or

In the event the Company is sold within five years of July 18, 2002, the Performance Warrants shall become exercisable, provided that the net realized equity value per diluted Common Share is greater than $\$3.00 \times 1.25^{n}$, where "n" equals the number of years (or partial years) since July 18, 2002. Net realized equity value is defined as the net cash liquidation value of the Company.

Common Shares underlying the Performance Warrants are contingently issuable shares, only issuable if the conditions for exercise of the Performance Warrants are met. If either performance target is not met, the Performance Warrants expire and no Common Shares will be issued. For this reason, the Performance Warrants are not included as a dilutive security until such time as either condition is satisfied.

(d) Stock Option Plan:

Under the Company's stock option plan, the Company may grant options to purchase Common Shares up to the maximum number permitted by the TSX Venture Exchange to directors, officers and employees. Options are granted at the market price, less permitted discounts on the grant date, vest according to privileges set at the time the option is granted, and must expire no later than five years from the date of grant.

As part of the reorganization of the Company, 816,667 management options exercisable at $3.00 were granted to the current management and 125,000 charitable foundation options were granted for the purpose of being put into the FirstEnergy Community Foundation.

As part of the business combination with Bolt (note 3), 325,004 options exercisable at an average price of $2.64 were granted through a rollover agreement to former employees, officers and directors of Bolt who became employees, officers and directors of the Company.

Following is a summary of options issued and outstanding at December 31, 2002.

Issued:

	2002			2001		
	Number of Options		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price
Balance, beginning of year (i)	11,280	$	0.40	11,280	$	0.40
Cancelled during the year (ii)	(11,280)	$	(0.40)	–		–
Granted during the year	1,266,671	$	2.79	–		–
Balance, end of year	1,266,671	$	2.79	11,280	$	0.40
Exercisable, end of year	393,754	$	2.77	5,640	$	0.40

(i) *Restated for 12.5:1 consolidation.*
(ii) *As part of the reorganization of the Company (note 2), all existing options were cancelled.*

5. Capital Stock (continued):

The following table summarizes information about stock options outstanding and exercisable at December 31, 2002:

	Options Outstanding		Options Exercisable	
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Number Exercisable	Weighted Average Exercise Price
$0.80 - $1.00	96,875	3.74 years	21,875	$ 0.80
$1.92 - $2.88	217,191	3.92 years	160,941	$ 2.45
$3.00 - $3.52	952,605	3.98 years	210,938	$ 3.21
$2.79	1,266,671	3.95 years	393,754	$ 2.77

(e) *Per Share Amounts:*

In computing diluted earnings (loss) and cash flow from (used in) operations per share, 59,009 shares (2001 – 11,280) were added to the 5,266,017 (2001 – 214,242) weighted average number of common shares outstanding during the year for the dilutive effect of stock options. In 2002, options to purchase 85,938 common shares were not included in the computation because they were out of the money. No adjustments were required to reported earnings (loss) and cash flow from (used in) operations in computing diluted per share amounts.

6. Stock-based Compensation:

The Company accounts for stock-based compensation using the intrinsic value method. Under this method, no costs are recognized in the financial statements for share options granted to employees or directors when the options are issued at market value. Effective January 1, 2002, Canadian Generally Accepted Accounting Principles require disclosure of the impact on net earnings using the fair value method for stock options issued on or after January 1, 2002. Had the fair value method been used, the Company's net earnings and net earnings per share would have been as follows for the year ended December 31, 2002:

	December 31, 2002 As Reported	December 31, 2002 Pro-forma
Net earnings (loss)	$ 210,497	$ (323,385)
Earnings (loss) per share, basic	$ 0.04	$ (0.06)
Earnings (loss) per share, diluted	$ 0.04	$ (0.06)

In calculating the pro-forma impact on net earnings, the fair value of options is amortized to compensation expense over the vesting period of the options.

The fair value of each option was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

Expected life (years)	3.73
Risk-free interest rate (%)	4
Volatility (%)	45

7. Income Taxes:

The provision for income taxes differs from the amount obtained by applying the combined Federal and Provincial income tax rate to earnings (loss) before income and other taxes as follows:

Period ended December 31	2002	2001
Statutory tax rate	43.1%	42.6%
Expected tax expense (recovery)	$ 233,162	$ (17,880)
Increase (decrease) resulting from:		
Non-deductible Crown charges and other payments	136,879	
Federal resource allowance	(87,457)	–
Change in enacted tax rates	(13,066)	–
Other	(1,886)	–
Capital taxes	62,849	–
Valuation allowance	–	17,880
Income tax expense	$ 330,481	$ –

The Company has available, subject to tax authority approval, tax pools of approximately $14.7 million as at December 31, 2002, including operating losses of $1.1 million. The Company also has capital losses in the amount of $1.2 million.

The components of the net future income tax liability are as follows:

	2002	2001
Property, plant and equipment	$ (3,437,183)	$ 1,113,250
Non-capital losses	484,687	–
Future site restoration	66,575	–
Share issue costs	536,051	–
Capital losses	540,483	–
Valuation allowance	(540,483)	(1,113,250)
	$ (2,349,870)	$ –

8. Financial Instruments:

The Company is exposed to fluctuations in commodity prices, interest rates and exchange rates. The Company monitors and, when appropriate, utilizes financial instruments to manage its exposure to these risks.

(a) Commodity Price Risk Management:

The Company periodically enters into oil and natural gas pricing agreements to provide it with exposure to a variety of pricing indices.

On February 5, 2003, the Company entered into a Commodity Swap/Cash Settlement Agreement for 200 barrels per day of crude oil for the period February 1, 2003 to January 31, 2004, at a fixed price of W.T.I .US$29.54 per barrel.

(b) Foreign Currency Risk Management:

The Company is exposed to foreign currency fluctuations. The Company may periodically use financial instruments, including forward-exchange contracts and currency options, to manage this exposure. At December 31, 2002, there were no contracts or options outstanding.

(c) Credit Risk Management:

Accounts receivable include amounts receivable for oil and natural gas sales. These sales are generally made to large, credit-worthy purchasers. The Company views the credit risks on these items as insignificant. Amounts receivable for joint venture partners included in accounts receivable are recoverable from production and, accordingly, the Company views the credit risk on these amounts as insignificant.

(d) Fair Values of Financial Instruments:

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities have carrying values that approximate fair value due to the near term maturity of these financial instruments.

9. Commitments:

The Company is committed to lease payments on office space, including operating costs and net of existing sub-leases, as follows:

2003	$	81,761
2004		61,168
2005		18,456

CORPORATE INFORMATION

Board of Directors

RANDY PAWLIW
President and C.E.O.
Blue Mountain Energy Ltd.
Calgary, Alberta

JAMES BANISTER
President and C.E.O.
BanCor Inc.
Calgary, Alberta
(Advisor to the Board)

RAYMOND CHIARASTELLA
Vice President, Land
Blue Mountain Energy Ltd.
Calgary, Alberta

VERNE JOHNSON
President
KristErin Resources Ltd.
Calgary, Alberta

CARL-MARTIN NAGEL
President
C.M. Nagel GmbH
Bad Vibel, Germany

Officers

RANDY PAWLIW
President and C.E.O.

RAYMOND CHIARASTELLA
Vice President, Land

NICHOLAS WEMYSS
Vice President, Exploration

BRENT FOSTER
Vice President, Engineering

DALE JOYNT
C.F.O. and Corporate Secretary

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ROYAL BANK OF CANADA
NATIONAL BANK OF CANADA
Calgary, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Independent Engineers

MCDANIEL & ASSOCIATES
CONSULTANTS LTD.
Calgary, Alberta

Registrar and Transfer Agent

CIBC MELLON TRUST COMPANY
Calgary, Alberta

Exchange Listing

TSX VENTURE EXCHANGE
Stock Symbol: GAS

Website: www.bme.ca

Email: info@bme.ca

Forward-Looking Statements – Certain information regarding Blue Mountain Energy Ltd. set forth in this document, including management's assessment of Blue Mountain Energy Ltd.'s future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Blue Mountain Energy Ltd.'s control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and ability to access capital from internal and external sources. Blue Mountain Energy Ltd.'s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Blue Mountain Energy Ltd. will derive therefrom.

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